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BEFORE THE CALIFORNIA ENERGY COMMISSION

Informational Proceeding and Preparation of the 2007 Integrated Energy Policy Report	Docket No. 06-IEP-1
and	and
Implementation of Renewables Portfolio Standard Legislation (Public Utilities Code sections 381, 383.5, 399.11 through 399.15, and 445; [SB 1078]	Docket No. 03-RPS-1078

Comments of Pacific Gas and Electric Company on the
2006 Integrated Energy Policy Report Update
Mid-Course Review of the RPS Process
July 12, 2006

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates this opportunity to provide written comments on the progress being made toward California's renewable energy resource goals, and the opportunity to participate at the workshop convened on July 6, 2006 ("Workshop") by the Integrated Energy Policy Report (IEPR) Committee and CPUC Commissioner Bohn ("Committee"), particularly the extra time to address the issues of greatest interest to the Committee. Fong Wan, Vice President of Energy Procurement, and Kevin Dasso, Senior Director of Asset Investment Planning, presented the views of PG&E at the Workshop. These written comments incorporate highlights from PG&E's presentation and respond to the 21 questions posed by the Committee's Notice in more detail than was possible at the Committee's well-attended Workshop.

A. PG&E's Procurement Experience Demonstrates That the Present RPS Program is Functioning Well.

The Committee's Workshop notice called for a mid-course review of the RPS program because, among other things, the percentage of CPUC-approved capacity coming on-line by 2010 has not been made publicly known. PG&E shared a summary of "PG&E's RPS Contracts to Date" at the Workshop which shows that approximately 600MW of PG&E's identified contracts will be on line before 2010; additional contracts are expected to result from negotiations with shortlisted bidders from PG&E's 2005 solicitation. PG&E has also prepared a table to demonstrate the results of its renewables procurement during the years 2001 through 2005. PG&E was in bankruptcy from 2001 until April 2004, and during this period of disability, could not execute long-term contracts. As widely acknowledged, the construction of new generating facilities will delay the commencement of deliveries for a period of several years from contract execution. Thus it is not unreasonable for PG&E's increase in renewable deliveries to be postponed for several years after 2004.

From the inception of the RPS program in 2002 to date, PG&E's combination of deliveries from existing renewable plants and contracted deliveries has increased from approximately 10% of PG&E's retail sales to about 15% of retail sales. By the end of the 2005 RFO, we expect this percentage to grow to approximately 16-18% of PG&E's load today.

The authors of the Workshop notice observe that only 240 MW of the more than 2000 MW of renewable capacity approved by the CPUC have come on-line and concludes that the state is not on track to meet the 20% renewables goal by 2010. PG&E believes that the uncertainty around achieving that goal is due to the timing realities of new power plant development and construction, not the RPS program. The following table, which shows actual renewable deliveries, and additional deliveries under contracts signed each year, illustrates PG&E's progress toward the 20% renewables goal.

Pacific Gas and Electric Company Renewable Energy Deliveries

YEAR	ACTUAL RENEWABLE DELIVERIES IN YEAR (MWH)	ACTUAL RENEWABLE DELIVERIES IN YEAR (% OF SALES) [1]	TOTAL RENEWABLE ENERGY UNDER CONTRACT FOR DELIVERY BY 2010 (% OF SALES) [1, 2]
2001	6,719,480	9%	9%
2002	7,391,867	10%	10%
2003	8,828,065	12%	13%
2004	8,590,682	12%	14%
2005 (Projected End of 2005 RFO Cycle)	8,650,362	12%	16% - 18% (Projected)

Notes:

1. All percentages are based on the retail sales for that year – 2001 % of sales is based on 2001 Retails Sales figure; 2002 % of sales is based on 2002 Retails Sales figure; etc.
2. Future deliveries from signed contracts are based on the applicable "solicitation year/cycle", even though the contracts may not have been executed and approved until the subsequent calendar year. For example, the deadline for contracts counting towards the 2005 Solicitation is September 30, 2006; to date, PG&E has three new signed contracts, and is expecting to execute a number of additional contracts (ranging from 2% - 4% of retail sales) prior to this deadline.

The CEC and CPUC have recently synchronized the mechanics necessary to carry out the Legislature's vision of incorporating renewable energy generation into California's energy portfolio. For example, the CEC promulgated new procedures for SEP applications in May of 2006. The CPUC accelerated the availability of the market price referent to the date on which the last utility stops accepting bids in response to its RPS solicitation (*See*, D.06-05-039, Appendix A.) The CPUC has been expeditious in reviewing and approving contracts, and in issuing decisions. With CPUC cooperation, PG&E issued its 2006 RPS solicitation just 2 days after CPUC approval of PG&E's compliance filing of its 2006 RPS Solicitation.

Now that the rules of the road have been clearly established, PG&E recommends allowing the program to work for several cycles before drawing any conclusions about the need for significant program change. This recommendation is shared by SCE and SDG&E, as well as the CEC's consultant, Black and Veatch, which stated, "Despite the complexity of RPS, significant contracting for renewables is underway." (Black and Veatch Workshop slide presentation, Conclusion.) The commercial reality is that projects can take several years to come online after regulatory approval; financing is contingent upon approved payment streams; the availability of production tax credits may influence the funding process; and the manufacture of equipment may take more time than anticipated. Any "mid-course correction" would tend to inject uncertainty into the commercial process and hinder, rather than assist, project development.

B. PG&E Must Be Able to Expand Its Access to Broader Renewables Markets to Enhance Procurement Opportunities and Consequently Avoid Price Run-Ups.

1. Out of state resources that provide banked and shaped deliveries should be recognized as "eligible renewable resources".

To meet our 20% target, PG&E has sought to gradually bring more eligible developers within range of our procurement capabilities. PG&E was recently allowed to expand its delivery points from the California Independent System Operator's (CAISO's) boundaries to all of California and must be allowed to expand further. There is a large amount of out-of-state renewable generation that can be tapped to meet load in California for purposes of the RPS goals. Such generation must be scheduled into California; given the finite ability of the transmission system to import power, PG&E recommends banking and shaping before the power is delivered to California. These two services result in the renewable generation being more adequately shaped to the needs of California consumers and allow such generation being delivered to these consumers mostly in the hours in which both the energy requirements and the availability of transmission into California are relatively high. Banking and shaping before the power is delivered to California will increase the renewable generation's usefulness to consumers by allowing the CAISO to more easily absorb the output into its generation mix and maximize the value of existing and future transmission.

The CAISO presently operates the Participating Intermittent Renewables Program (PIRP), which allows deliveries from renewable intermittent generators to be absorbed by the CAISO based on a forecast schedule and independent of the actual generation. In essence it looks as if CAISO absorbs the generation output within its system, banks this energy and delivers the energy to the purchaser during scheduled delivery periods. Thus, the PIRP allows renewable intermittent generators to sell power according a schedule different from the actual generation; this makes the generation more valuable to the load serving entities because deliveries are more predictable, and allows the intermittent generator to receive payment for actual generation, not for scheduled generation. The generator's actual deliveries and the scheduled deliveries are compared and trued-up on a monthly basis. All PIRP-coordinated power is counted toward the IOUs' RPS goals.

A similar approach should be applied to out-of-state renewable generation. That is, the CEC should determine that banked and shaped output of an eligible out-of-state renewable resource should count towards RPS targets when delivered to the CAISO. In order for this to occur, the power must be banked and shaped before being delivered into the state. The analogy between the PIRP program for intermittent generators and banking and shaping for out of state generators is clear. Both allow deliveries to customers to occur on the basis of a schedule while the generator's output is different from this schedule. Generators are getting paid for actual generation and load receives a banked and shaped product. This is made possible by the CAISO, in the case of PIRP, and by an out-of-area entity able to provide banking and shaping services for out-of-area generators. However, there is one important difference. Deliveries under PIRP are trued-up on a monthly basis as they are directly absorbed by the CAISO into its system. However, for out of state generators, allowance should be made for deliveries to be trued up on an annual basis. That is necessary because out of state deliveries will be most valuable in those hours in which need for energy and transmission availability are compatible.

To enable out of state generation from renewable resources to provide the best value to California's consumers, the CEC should include within its definition of "eligible renewable resources" out of state generators that generate electricity and deliver it or "bank it" with a third party for delivery at a time that is advantageous to the purchaser subject to a one-year maximum true-up period. PG&E anticipates filing banked and shaped contracts for CPUC approval in the future and looks forward to adding these renewable energy generators to the pool of resources available to meet our 20% goal at a reasonable cost.

2. Contracts should not be ineligible for SEPs due to limited indexing of the purchase price.

The CEC should be aware that in a commercial setting, it is not uncommon for the buyer to retain the risk of cost escalation due to factors such as inflation or other specific input. It is recognized that this type of accommodation relieves the seller of the cost of compensating for the risk and could result in a lower price being offered to the buyer. PG&E believes that such risk sharing could be accommodated in its renewables power purchase agreements, given acceptable limitations on the percent of purchase price at risk and the escalation factor. However, the

CEC's present methodology for calculating supplemental energy payments (SEPs) yields a fixed price payment for the entire payment period. This limits the availability of SEPs and potentially deprives potentially lower-priced projects of funds needed for realization of their development. PG&E encourages the CEC to work with stakeholders to find a way for its SEP process to accommodate indexed, or otherwise escalating power purchase prices.

C. PG&E Is Actively Upgrading its Transmission System to Accommodate Areas of Identified Renewable Potential As Well As Aggressively Planning for Large Scale Transmission Expansion.

The CEC asserts that utilities are wary of investing in renewable transmission without assurance of cost recovery, which is premised on the renewable generation being built, and that at the same time, renewable projects cannot secure contracts without knowing whether existing transmission will be there to accommodate them. The CEC also observes that the intermittent nature of some renewable resources can have impacts on the reliability and operation of the existing grid.

PG&E appreciates the need for additional transmission to meet RPS goals. PG&E has been moving forward with a number of cost-effective transmission projects to relieve transmission constraints in renewables-rich areas, and PG&E remains committed to making the investments necessary to accept the renewable resources on a non-discriminatory basis where the resources may be located within PG&E's service territory.

With billions of dollars of potential transmission investments on the table, we believe we owe it to our customers to make good choices. The basis for locating and developing transmission interconnection resources will be least cost – best fit principles. PG&E's approach is to use RPS bid solicitation results to guide transmission investments to access renewable resources that are most likely to develop in the near term, and:

- Pursue multi-purpose projects (reliability, congestion reduction, and RMR reduction) and near-term projects that can provide access to resources quickly
- Continue to pursue longer-term, large scale, multi-purpose transmission expansion projects in parallel with the schedule of multi-purpose nearer term projects.

PG&E has identified five projects in its 2005 Transmission Grid Expansion Plan that are needed for reliability and/or to promote economic efficiency, and will also foster the development of least cost, best fit renewable resources. PG&E plans to seek project-specific ISO Board of Governors approval in accordance with ISO tariff requirements beginning in the third quarter of 2006, in 3 phases. PG&E expects that the ISO will include the remaining projects as part of PG&E's 2006 grid expansion plan.

Phase 1 would consist of the following:

- The portion of Vaca Dixon - Contra Costa 230 kV Reinforcement to provide transmission capacity needed for renewables connecting between Vaca Dixon and north of Vaca Dixon
- Table Mountain – Rio Oso 230 kV Reconductoring, which is part of the Table Mountain – Vaca Dixon 230 kV Reinforcement to help access renewables in the vicinity and north of Table Mountain Substation.
- Vaca Dixon - Tulucay 230 kV Reconductoring to help access renewables in the vicinity and north of Vaca Dixon Substation

PG&E anticipates seeking ISO Board approval for the following Phase 2 projects, as required, during the fourth quarter of 2006 – first quarter of 2007:

- Midway – Gregg 500 kV Line to enable access to renewables in the vicinity and south of Midway Substation
- Cottonwood – Vaca Dixon 230 kV Capacity Increase to enable access to renewables in the vicinity and north of Cottonwood Substation

Phase 3 projects will be investigated after approval of projects in phases 1 and 2 depending on further studies and projected need:

- Vaca Dixon – Sobrante – Moraga 230 kV Reinforcement to increase access to renewables north of Vaca Dixon Substation
- Remaining parts of Table Mountain - Vaca-Dixon 230 kV Reinforcement to increase access to renewables in the vicinity and north of Table Mountain Substation

PG&E shares the CEC's concern that the intermittent nature of some renewable resources can affect the reliability and operation of the existing grid and has been following the work of the Public Interest Energy Research (PIER) Program renewable energy program Intermittency Analysis Project (IAP) with interest. PG&E looks forward to receiving the next IAP report and will continue to support the PIER efforts.

The CPUC has recently acted to provide utility transmission owners with cost- recovery mechanisms to mitigate the utility's risk that the cost of developing transmission interconnection facilities for renewable development may not be recovered in FERC rates.[1] The CPUC has also taken steps to expedite the transmission siting process under General Order 131-D. We encourage the CEC to further assist in all parties' efforts to expedite the siting of renewables-driven transmission by fully analyzing the environmental impacts of transmission interconnection facilities as part of its review of renewable generation permit applications, which will shorten the length of time needed for the subsequent CPUC siting process.

[1] *See*, D.06-06-034, which enables a utility transmission owner to apply for CPUC rate recovery of its cost to interconnect a renewable resource under contract, if the transmission cost is not recovered under FERC tariff. See also the CAISO's White Paper, "Proposal for a Third Category or Alternative Treatment of New Transmission Facilities for Renewable Generators", June 28. 2006.

D. Although Transmission Is Still a Potential Bottleneck, PG&E Has Adapted Its Transmission Evaluation Process to Anticipate and Meet the Needs of Likely Renewables Projects and Offers Alternatives to Transmission Upgrades to Renewables Developers.

The discussion on the use of the transmission ranking cost report (TRCR) revealed that many participants are unfamiliar with how the TRCR is integrated into the bid evaluation process.

The Legislature has determined that the cost of interconnection must be considered along with the cost of generation when determining which potential generator is the least-cost best-fit generator. The transmission ranking costs set forth in the TRCR are designed to replicate as closely as possible the costs of the transmission facilities that will be required by the ISO as a condition of interconnection of each RPS bidder's generation facility. The TRCR is intended to provide a proxy that would allow RPS bidders to avoid the costs associated with the ISO Interconnection Process before bidding into an RFO.[2] The TRCR establishes a cost for each interconnection point during a snapshot in time, to be used simultaneously for all bids participating in a solicitation. The cost of transmission is imputed from a common scenario to each renewable bid to calculate the total cost of each proposed project to the consumer.

However, a proposed project may avoid the imputation of a transmission cost adder for bid evaluation purposes by submitting a generation profile by agreeing to curtail deliveries during the period of transmission shortage identified in the TRCR for its associated cluster, and thereby avoid creating the need for a transmission upgrade. Under those circumstances, interconnection of the new generation would not cause the reliability criteria violations that would otherwise occur, and the ISO would not condition interconnection of the new generation on construction of new transmission. As such, the total cost to customers associated with that particular RPS bid would not include any indirect transmission cost, and no TRCR bid adder would be applied.

In addition, for proposed projects located in a market in which the generation can be sold and PG&E can obtain replacement power, the net result of the transaction will be compared to the otherwise imputed TRCR cost, and the lower of the two costs will serve as the "transmission adder" for purposes of bid evaluation. The CPUC has determined that, in some cases, a retail seller may accept delivery of renewable generation at a location in California and then schedule the power to serve local load, such that transmission costs and congestion can be avoided. In such cases, selection of the particular RPS bid will not result in additional transmission costs to bring the renewable resources to customers, but will result in remarketing and other transmission costs. These indirect transaction costs may be imputed to the bid in question in order to meet

[2] If the RPS bidder has already obtained a cost estimate through the ISO Interconnection Process, PG&E will use that estimate for purposes of evaluating the total cost of the bid, rather than the estimates in the TRCR

least cost, best fit bid evaluation requirements, if they are less than the otherwise-applicable transmission upgrade cost. However, this is not always cost-effective in every market. The lower of the commercial transaction cost and the TRCR cost must be imputed to the project's bid.

The TRCR methodology is intended to properly reflect the "real world" cost to customers associated with each RPS bid, as required by the Legislature. Because all renewable bidders are evaluated against a common transmission availability scenario, there is no possibility of geographic, resource technology, or other form of discrimination. In addition, the information set forth in the TRCR informs developers of the likely costs associated with interconnection at various points on the grid, and encourages them to make use of existing transmission resources where possible. However, as noted in PG&E's RPS Solicitation Protocol, the TRCR costs at each substation are only generically-priced proxies for the actual expense that an individual generator would pay upon interconnection.[3] The most accurate estimate of interconnection costs would be the results of individual generators' SIS/FIS studies, which PG&E will use for bid ranking purposes wherever available.

II. RESPONSES TO SPECIFIC QUESTIONS PRESENTED BY THE WORKSHOP NOTICE

Increasing transparency

1. Ways to make the least-cost, best-fit process more transparent.

The term, "least cost best fit" (LCBF) refers to the total cost characteristics of the renewable energy resources that are to be procured to fulfill California's RPS goals.[4] The least cost best fit evaluation is simply a way to select the bids that provide the best value for the consumer.

PG&E lists the different evaluation criteria that are part of the least-cost, best fit process and describes how each bid is measured against the criteria on pages 36 through 39 of its 2006 RPS Solicitation Protocol. The financial criteria include the broad categories of Market Valuation, Portfolio Fit, Transmission Cost Adders, and Integration Costs. In response to comments by some Workshop participants, PG&E will provide an extended overview of its bid evaluation criteria at the Bidder's Conference to be held on July 20, 2006.

PG&E's Protocol explains how each criterion is integrated into the RPS bid evaluation process. Market valuation captures net market benefit. Portfolio fit compares a project's online date and generation profile with PG&E's portfolio needs. Transmission cost adders – if any, after taking into account voluntary curtailment -- whether from an ISO interconnection study, alternative commercial arrangements, or from a Transmission Ranking Cost Report -- are also

[3] The customers will reimburse the generator for the Network portion of the expense with interest in five years after the generator comes on line according to FERC Interconnection Rules.

[4] Pub. Util. Code Section 399.14 subsection (a)(2)(B).

factored into bid ranking. Integration costs are considered, consistent with CPUC direction to rely on the results of the integration studies conducted by the CEC.

In its 2005 RPS solicitation, PG&E engaged an Independent Evaluator to oversee the process and to provide regular updates to the CPUC and Procurement Review Group (PRG) on the solicitation. The CPUC has expanded the role of Independent Evaluators, starting with the 2006 RPS solicitation, to include the issuance of a formal Independent Evaluator Report. This additional layer of oversight and reporting should provide reassurance that the LCBF process is being followed.

> 2. How to simplify the process used to determine the market price referent (MPR), including how time-of-delivery factors are derived and applied, and ways to ensure that assumptions used are the same as those used in the CPUC's all source procurement so the two procurement processes are consistent.

PG&E supports a simplified process in determining the market price referent (MPR). As with any new process, the initial MPR methodology has required a significant investment in time and resources from the CPUC and market participants. As this methodology has been established, determining the MPR should be quicker in the future. The development of MPRs in future years can be simplified by focusing on a limited set of methodology or input assumptions each MPR cycle while postponing the re-examination of the other input assumptions until a subsequent cycle.

PG&E continues to believe that utilities are in the best position to develop utility-specific time of delivery (TOD) factors. Utility-specific TOD profiles capture regional differences in the value of power during different time periods and they reflect the underlying basis of each utility's resource procurement methodology. PG&E believes that its process in developing TOD factors is straightforward; it is described in its TOD Benchmarking Study and the February 8, 2006 Supplement to the Draft 2006 Renewables Portfolio Standard Solicitation Protocol of Pacific Gas and Electric Company.

PG&E already uses the same underlying PG&E hourly price streams to create PG&E's TOD factors for the RPS process as the foundation for market valuation in other PG&E all-source solicitations. If PG&E were to conduct several solicitations at the same time, it would use the same underlying price inputs across all solicitations.

> 3. How best to balance utilities' desire for confidentiality with policy makers' need to complete bid data in order to appropriately award supplemental energy payments (SEPs).

PG&E affirms that it is willing to provide any and all confidential data to the CEC staff to inform the CEC's decision-making process. However, information received by the CEC is subject to public disclosure, unless it is afforded confidential treatment by the CEC. Because the information concerning SEP awards generally constitutes market sensitive data, PG&E is concerned that the dissemination of this information may be detrimental to its customers. This is the sole reason PG&E desires confidentiality for SEP information. This has been our consistent position and creates no conflict between the CEC's need for bid data and the need for confidentiality.

The CEC's Guidebook contains two primary forms of data requests, the CEC "Bid" data requests and SEP application data request. PG&E recognizes that the public interest in a SEP award may outweigh the developer's privacy interests, so that information relating to a SEP-funding project may be released. However, PG&E has serious concerns about the release of the requested Bid data, which includes the price, annual volumes, contract length, start year, and percent contribution to the utility's RPS obligation, of every bid submitted in response to the utility's RPS solicitation. PG&E recommends that the data from all bids, whether resulting in contracts or not, should remain confidential, and also recommends keeping confidential the specific terms and conditions of contracts for which SEP funds are being sought.

a. There are several compelling reasons to protect all of the submitted bids from public disclosure.

First, bidders compete against other bidders in competitive solicitations and often compete in several solicitations simultaneously. The disclosure of bid information may disadvantage the bidder in relation to other bidders.

Second, releasing bid information violates the agreement between bidder and PG&E that the terms of the bid will be treated confidentially. The release of detailed supplier bid information would likely stifle competition in the market. Bidders would be reluctant to provide true bids if they believed their proprietary information would be made public.

Third, it discloses a bidder's proposal to its competitors and may be used in other solicitations, to the detriment of utility customers. The worst winning bid can become the *de facto* floor for pricing and terms for the next round of procurement.

Fourth, the bid information will inform potential suppliers exactly what quantity of resources were bid, and if there is a perceived shortage in bid quantities, bidders will use this information to increase bid prices.

Finally, there should be no need for the CEC to perform additional analyses on offers that either did not win in the solicitation or did not request SEP funds solely to allocate SEP funds. This work would be duplicative, and could substantially delay the SEP award process.

b. Specific contract terms and conditions, even for a contract requesting SEP funds, should remain confidential.

There is no public purpose to be served by the disclosure of the terms of a contract for which SEP funds are being requested. The release of contract terms and conditions could encourage future supply bidders to demand the most advantageous terms of each contract. The proliferation of "most favored nation" clauses would erode the bargaining power of the utility's customers.

The terms of an SEP-eligible contract and the process by which it was selected are transparent to parties who need to know this information for a public purpose, that is, to oversee the impartiality and reasonableness of the bid selection process. The Procurement Review Group, which consists of non-market participants such as the CEC staff, CPUC staff, and ratepayer advocates, was consulted 8 times during the 2005 RPS RFO process. In addition, the 2005 solicitation is being monitored by an Independent Evaluator (as will subsequent RPS solicitations). Thus, by the time winning bidders make their applications to the CEC for SEP funding, the winning contracts have already been evaluated against other renewable resource offers and have been determined to provide the best value for customers. Further dissemination of winning contracts to the general public would not provide any benefit, but could result in an increase in bid prices as described above.

<u>Ensuring that renewable procurement occurs quickly and efficiently</u>

4. Are further steps needed to get RPS solicitations on an annual cycle with pre-established dates for release of RPS solicitations, when bids are due, selection of short list bidders, and approval of contracts?

A twelve-month cycle of pre-established dates for each step of the solicitation process should not be required because rigid deadlines that ignore the specific conditions of each solicitation would not necessarily allow sufficient time to select the best projects and may result in contracts with prices and terms less favorable to PG&E's customers.

It is reasonable to establish a tentative date for publication of the shortlist, as was done by the CPUC decision approving the utilities' 2006 RPS solicitations, D.06-05-039. However, the CPUC held that the adopted schedule should be modified as necessary to bring the next solicitation to a reasonable conclusion by early 2007. This practical solution encourages the utilities to observe the Commission's preferred schedule but allows for extensions pursuant to notification by the utilities. There may be circumstances beyond a bidder's or PG&E's control that delay the shortlisting process, and the application of a rigid procedural requirement could limit the eligible pool of potential sellers for no good reason. Likewise, a mandatory uniform deadline for submission of contracts by each of the utilities would only tend to eliminate potentially viable projects.

PG&E believes that its solicitation schedule must be flexible enough to accommodate the particular results of each solicitation. The CPUC has also accommodated the fact that IOUs would have at most six months to solicit projects during 2005 and 2006 if the procurement cycles had been constrained to a calendar year cycle. The CPUC's orders have provided sufficient guidance to establish how contracts signed after the end of the calendar year may be used to demonstrate compliance.[5]

Since the inception of its RPS solicitation process, PG&E has functioned in a timely manner. Bidders have expressed satisfaction with PG&E's schedule. Bidders are well aware of the dates for release of RPS solicitations, when bids are due, selection of short list bidders, and approval of contracts. No further steps are needed to get RPS solicitations on an annual cycle.

5. In D.06-05-039, the CPUC allowed IOUs to use their contingency planning to account for contract failure in procuring sufficient energy to achieve 20 percent renewables by 2010. Are further steps needed to trigger additional procurement if contract failure exceeds IOUs' expectations?

No additional steps are needed to trigger utility procurement in the event of contract failure. D.06-05-039, issued by the CPUC on May 26, 2006, addressed this very issue. The CPUC found that PG&E's continuing *voluntary* overprocurement plan, coupled with additional milestone reporting, is sufficient to keep PG&E progressing as quickly as possible toward achieving the 20% renewables target by 2010.

PG&E believes that voluntary overprocurement is sufficient, even in the event of a 20% to 30% contract failure. In 2004, PG&E's renewable procurement, as measured by contracts for future deliveries, exceeded 2% of its retail sales volume, resulting in a GWh figure that was nearly 230% of the mandatory target. PG&E currently anticipates signing contracts resulting from its 2005 RPS solicitation for the delivery of renewable generation totaling 2-4% of its annual sales. PG&E will include a margin of safety in its 2006 procurement.

Utility overprocurement should be voluntary and based upon the quality of bids relative to resource needs. PG&E is concerned that a mandatory margin of safety would be unreasonable because there is no assurance that each solicitation will provide a sufficient number of high-quality, reasonably priced bids to meet an overprocurement target. Forced overprocurement may lead to a portfolio of resources that are not least cost, best fit, or sufficiently viable to provide the desired "safety net" in the first place.

In addition, PG&E is now *required* to provide "limited additional reporting on the progress of each project meeting its development and initial operation milestones in the form of semi-annual compliance reports to the Energy Division of the CPUC. Specific notice must be provided to the Energy Division when a major project milestone is missed. Based on these requirements, the CPUC declined to adopt a mandatory 20% overprocurement requirement. (*See*, D.06-05-039, conclusion of law 3.b.)

Even the CEC's Margin of Safety Report did not propose an overprocurement mandate. The Report recommended monitoring of contract failure rates by the utilities and regulators. This recommendation has already been implemented by PG&E use of project viability criteria,

[5] *See,* D.06-06-066 ordering paragraph 8.

credit requirements, the PRG's thorough monitoring, and the Independent Evaluator's oversight throughout the entire procurement process. Since PG&E has a margin of safety, which is now required by the CPUC, and monitors and reports the progress of each development under contract as required by the CPUC, there is no need for overprocurement. The potential penalty mechanism adopted in D.03-06-071 provides the utilities with sufficient incentive to trigger additional procurement if project development does not occur in a reasonable manner.

6. Recognizing that the CPUC plans to address applying the renewable "rebuttable presumption" consistently to all procurement, the IEPR-RPS midcourse review provides an opportunity to catalyze innovative ideas to be further developed in that process. What suggestions do you have on this topic?

PG&E complies with the "rebuttable presumption" that supply side resource needs should first be met with renewable resources by following the Energy Action Plan loading order. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, the Commission supports clean and efficient fossil-fired generation.

PG&E's recent all-source Request for Offers (RFO) sought products that did just that – filled needs that the preferred resources had not filled. The preferred resources available to us did not fill our needs for dispatchable and peaking resources. As the title implies, the all-source RFO was open to all resources; however, no renewables were bid into that RFO. That is not a sign of failure of the RFO, it is simply an indication that (1) the renewables available in the market had been offered in the 2004 and 2005 RPS RFOs, which overlapped with the 2005 all-source RFO, and (2) renewable technologies available today are not capable of providing reliable, competitive dispatchable and peaking products.

The Commission's "rebuttable presumption" was satisfied because PG&E's selection of gas-fired resources filled in the gap and did not displace any renewable resources. PG&E suspects that the availability of Supplemental Energy Payments in the RPS RFO but not in the all-source RFO also affected in which venue renewables capable of offering peaking products chose to bid. As one of the Workshop participants observed, the lack of renewables capable of responding to a solicitation for dispatchable and peaking resources indicates the need for the technological development of renewables.

Addressing transmission and integration issues

7. Strategies to address the current CA ISO interconnection queue process, which may be preventing successful renewable generation projects from being constructed.

Current FERC open access policy requires that no single source of generation is preferred in the transmission interconnection process. The CAISO interconnection process currently complies with this policy and considers resources on a first-come, first-served basis. If compliance with the FERC open access policy is responsible for preventing the construction of new renewable generation projects, the matter must be addressed to FERC.

In the interim, PG&E believes improvements to the efficient processing of the queue are needed to foster both renewable and conventional generation development. Administration rules concerning the interconnection queue should be modified to move generation projects through the process more quickly and efficiently. Projects with little practical potential for development should be removed from the queue after a reasonable period of time. Improvements to the interconnection queuing process could be implemented expeditiously and would provide more opportunity for quicker access to any existing transmission capacity that may be available for interconnection of renewable resources. Given that FERC oversees the CAISO interconnection and queuing process under national guidelines, changes in queuing priority could be difficult to implement in the near term.

8. How to modify the current transmission interconnection process so that existing users of transmission, primarily fossil-fueled generators, are not given priority for current transmission capacity while renewable generators, the preferred resources in the state's loading order policy, are required to upgrade transmission to gain access to the grid.

Current FERC open access policy requires that no single source of generation is preferred in the transmission interconnection process. The CAISO interconnection process currently complies with this policy and considers resources on a first-come, first-serve basis.

The assumptions and study process used in the TRCR and the system interconnection study (SIS) adhere to Western Electric Coordinating Council (WECC) Policy[6], which states, among other things, that "[n]ew facilities and facility modifications should not adversely impact Accepted or Existing Ratings regardless of whether the facility is being rated. New or modified facilities can include transmission lines, generating plants, substations, series capacitor stations,

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[6] The Policies and Procedures for Regional Planning Project Review, Project Rating Review, and Progress Reports, Page 28, (http://www.wecc.biz/documents/library/procedures/planning/Overview_Policies_Procedures_RegionalPlanning_ProjectReview_ProjectRating_ProgressReports_07-05.pdf.
In Appendix A of this same document WECC defines "Adversely Impact Transfer Capability", "Benchmark Case" and "Comparison Cases" as follows:
Adversely Impact Transfer Capability - Adversely impact transfer capability means the reduction of either the Simultaneous or Non-simultaneous Transfer Capability. A new project causes a significant and verifiable adverse impact that needs to be mitigated if it reduces the transfer capability of a rated Project in a Benchmark Case comparison.
Benchmark Case - Case(s) that model the existing system (including appropriate recognition of other projects in the Rating Process) in the timeframe of new project and show the maximum transfer capabilities (e.g. the Existing or Accepted Rating) of existing paths that may interact with new project.
Comparison Cases - Cases with the new Project showing range of desired operation of new project and illustrating whether or not there are impacts or interaction with existing projects.

remedial action schemes or any other facilities affecting the capacity or use of the interconnected electric system."

This policy is needed to maintain reliability. In general, reliability of service to customer consists of two parts: Supply and Transmission. Transmission congestion means that generators in certain areas may not be able to generate due to transmission constraints. If enough generators are constrained off, supply would become less reliable. At some point, transmission congestion will cease to be an economic problem and become a resource adequacy problem. Therefore, the planning philosophy in the power industry has been to maintain transmission system reliability after each addition to the system. This policy is codified in the WECC Policy mentioned above and applies to interconnecting generation projects, new or upgraded transmission projects, and interconnection with other areas.

All participants of the power grid have an obligation to contribute to maintaining reliability. Otherwise, the reliability of service to customers will degrade with each addition to the system.

In addition, once interconnected and integrated, a generator should not be on the margin and at risk of losing its transmission access. Otherwise, with its access to markets continually at risk, developers would not be able to obtain financing for their projects. While the transmission needs of renewable generation must be accommodated, accomplishing this objective at the expense of other generation would seriously threaten the construction and delivery of generation neccessary to maintain system reliability. In any case, network facilities are paid for by the customers because the developers would be reimbursed after the generation project comes on line, with interest. As such, the impacts on customers must be accounted for in procurement resources.

However, better communication between various parties in the CAISO interconnection and transmission study processes is needed to ensure that retiring existing generation (primarily fossil-fueled generation) is removed from transmission system study models at the earliest possible date after retirement has been confirmed. This improvement should reduce the amount of transmission capacity withheld to hedge against the uncertainty of likely generation retirements and lead to greater transmission availability for renewable and other types of more efficient new generation resources.

9. Ways to amend the CA ISO tariff to allow the interconnection of large concentrations of renewable generation resources located within a reasonable distance of the existing CA ISO grid; including a recently proposed CA ISO request for a declaratory order on renewable transmission from the Federal Energy Regulatory Commission.

PG&E supports exploring all avenues for building cost effective transmission improvements necessary to interconnect large concentrations of renewable resources. The recent

CPUC Final Decision in I.05-09-005 on backstop cost recovery under Public Utilities Code 399.25 helps resolve some of the significant issues associated with interconnecting renewable generation. In addition, the existing CAISO Tariff provisions provide broad authority for the ISO to approve projects needed for reliability or to promote economic efficiency.

Many transmission upgrades capable of fostering the development of large concentrations of renewable resources, such as the Midway-Gregg project, clearly meet these existing standards. PG&E plans to participate in the current CAISO stakeholder process addressing any special criteria for evaluating transmission necessary for meeting RPS goals. PG&E also supports the CAISO's efforts to update its transmission evaluation criteria to address situations where shared gen-tie facilities could qualify for utility funding, to better reflect California's RPS goals. To ensure consumers receive the most cost effective solutions, boundaries similar to the recent 399.25 decision need to be incorporated into the evaluation criteria.

10. How to ensure that transmission cost estimates in the investor-owned utilities' Transmission Ranking Cost Reports used to evaluate RPS bids are appropriate and do not impose new barriers to renewable development.

A common misconception of the TRCR is that it can make renewables appear uneconomic compared to non-renewable generators. The TRCR is used to compare renewable generators to other renewable generators so that utilities can use LCBF criteria when choosing among them. If the TRCR indicates that a particular bid would require customers to incur significant transmission interconnection costs, yet that bid is still the overall LCBF bid, it will be selected despite the high transmission costs. RPS goals must be met in any event, and procuring non-renewable generation with lower transmission costs is not an option. Therefore, the premise of this question -- that the TRCRs could impose barriers to renewable generation development – is incorrect.

The TRCR is an initial screening tool designed to (1) reflect as accurately as possible the cost of transmission upgrades the ISO will require as a condition of interconnection of a particular bid, thereby allowing all stakeholders to understand the total costs (direct and indirect) associated with each bid as required by the Legislature, and (2) provide timely information concerning the transmission system to RPS developers so that they can develop their projects and structure their bids in ways that maximize their chances of being selected. Abandoning these principles might result in a different (and more expensive) set of winners, but it would do nothing to increase the overall level of procurement. Finally, PG&E notes that the TRCR is subject to third party comment and CPUC review, and is the subject of an ongoing CPUC investigation. PG&E's 2006 RPS Solicitation Protocol states that PG&E will consider the least expensive alternative (CAISO Interconnection Study results, TRCR cost adder, or alternative commercial arrangements) when evaluating the transmission cost of each bid. In any event, such costs must continue to be considered in the bid evaluation process in order to satisfy the

Legislature's LCBF requirements. The Legislature knew what it was doing in requiring the utilities to consider the "real world" transmission costs associated with RPS bids. If the utilities were permitted to ignore these costs for bid evaluation purposes, the result would be the procurement of renewable power with greater overall costs to California customers, and the construction (and associated environmental impacts) of transmission projects that could have been avoided by selection of other, lower cost renewable projects.

As mentioned above, the TRCR follows WECC Policy to assure reliability of the grid would be maintained as facilities are added and assumes that the renewable resources would displace conventional generation at load centers starting with the oldest units. Arbitrarily displacing generation that could compete with the generation to be added (in this case renewable generation) could skew the results and affect existing transfer capability.[7]

As mentioned above, the developer can also adjust its generation profile under PG&E's RPS Protocol to avoid triggering the transmission ranking cost in the TRCR. In addition, PG&E's 2006 RPS process will consider, up front, all viable alternative commercial arrangements to the transmission upgrades included in the TRCR.

A more accurate estimation method than the TRCR also can be achieved through the CAISO interconnection process. The developer may enter the ISO Interconnection process to obtain a project-specific cost estimate before responding to the solicitation and submit that cost estimate with its offer in accordance with CPUC Decision 04-06-013.

11. Focusing state research and development efforts on issues surrounding integrating large amounts of intermittent renewable resources into the state's electric grid without adversely affecting reliability or system operations.

PG&E will continue to actively support these efforts. PG&E is concerned about the potential adverse operational consequences of incorporating large quantities of intermittent renewable generation into the existing generation portfolio. PG&E supports recent CAISO and WECC efforts to further evaluate these operational and reliability challenges.

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[7] For example, in conjunction with the Tehachapi Collaborative Study, PG&E did study an alternative which assumed displacing generation connected to Midway Substation[7] (or Midway generation) instead of the older conventional generation in the San Francisco Bay Area. Because Midway generation is part of the remedial action scheme to support the existing transfer capabilities of Path 15 in the south to north direction (of 5,400 MW), and Path 26 in the north to south direction (of 4,000 MW), transfer capabilities on both Paths have to be reduced under normal operating conditions in accordance with WECC Planning Standards and Operating Policies.

Applying RPS targets consistently to all load-serving entities

12. Regarding ESPs and CCAs, should the MPR and SEP processes be applied, and, if so, how should these be applied for contract terms of less than 10 years.

The MPR should apply to all electrical corporations, including IOUs, ESPs and CCAs. Supplemental Energy Payments (SEPs) should be provided by the Energy Commission from funds in the New Renewable Resources Account of the Renewable Resources Trust Fund to eligible renewable resources for above market costs. Eligible Renewable Resources with contracts with IOUs, ESPs or CCAs, should all have equal access and similar processes for obtaining SEPs. Eligible renewable resources with contract terms less than 10 years should not be eligible for SEPs. Projects built on a merchant basis should not be subsidized by the public good funds; the purpose of SEPs is to encourage long-term investment in new renewable resources.

13. What further actions are needed to ensure that publicly owned utilities, ESPs, and CCAs meet the same targets, timelines, and eligibility standards as IOUs, and what type of exemption process is needed to avoid overly burdensome requirements for smaller entities?

The CPUC is addressing this issue and expects to issue a decision on RPS implementation for ESP, CCA, and small and multi-jurisdictional utilities. The decision should standardize the targets, timelines, and eligibility requirements for ESPs, CCAs, and IOUs. Exemptions for smaller entities should be handled on a case-by-case basis and should reflect their unique circumstances.

With respect to publicly owned utilities, new legislation is required to ensure they meet the same targets as other load serving entities. The CEC, as the agency with lead responsibility for developing a state-wide energy policy, is in a unique position to propose solutions to the Legislature to ensure that all load serving entities, including publicly owned utilities, operate under the same rules. Legislation should require publicly owned utilities to meet the same targets, timelines, and eligibility standards as IOUs.

14. How to implement the 2005 Energy Report recommendation to explore limited use of renewable energy certificates for RPS compliance to facilitate uniform participation by all load serving entities.

PG&E supports the concept of using renewable energy certificates for RPS compliance. PG&E supports the direction the CPUC is currently taking regarding RECs. PG&E recommends that the use of RECs be applied equally to all load serving entities. PG&E also recommends using RECs for RPS compliance as a compliment to long-term contracting, not as a substitute. Having some portion of RPS compliance eligible for RECs could dovetail with the state's implementation of WREGIS, expected to be operational in mid 2007.

Streamlining accounting for RPS compliance

15. The desirability of establishing a single RPS target reflecting the total amount of renewable generation needed each year to meet the 2010 RPS goals.

In general, PG&E supports simplifying the RPS compliance process. However, a significant amount of time and effort has been expended by the CPUC, CEC, and the many interveners to arrive at the numerous regulatory decisions on RPS compliance. While other approaches may have merit, PG&E believes it would be counterproductive at this stage to establish a single RPS target for RPS compliance. The single RPS target would also need to be customized for each utility and contain enough flexibility to allow for varying depth of each annual RFO. Making such a change would certainly require the parties to debate again the same RPS compliance issues that have gone into establishing RPS targets for annual and incremental procurement. Such a renewed debate would distract the parties from the primary task of increasing RPS procurement, and may not yield meaningful streamlining benefits.

16. Whether statutory requirements that generation from specific geothermal, small hydro, and municipal solid waste combustion facilities apply only to the baseline are still necessary, and whether those restrictions would hamper movement to a single RPS target.

PG&E does not currently have a recommendation on this issue.

17. Whether statutory requirement applying to incremental geothermal should be removed.

PG&E does not currently have a recommendation on this issue.

18. How generation from renewable distributed generation facilities is counted toward RPS compliance, including resolving issues related to public subsidies and measurement.

These issues are being addressed by the CPUC in R.06-03-004. However, PG&E's position is a simple one: The utilities' customers are spending approximately $3 billion on solar incentives. To the extent that PG&E customers are subsidizing renewable distributed generation facilities through incentives or other means, PG&E's customers should be entitled to count the output from the subsidized facilities toward meeting the utility's RPS obligations. Further, the CPUC has already indicated its intent to allow utility customers to count at least a portion of subsidized renewable DG towards their RPS requirements. PG&E agrees with the proposed scope of R.06-03-004 to consider questions associated with the portion of the renewable energy credit (REC) subsidized by customers, potential methods for allocating the REC, and specifics associated with measuring and counting the DG facility output.

Addressing jurisdictional issues and financing

19. How California should apply prevailing wage requirements to out-of-state facilities wishing to receive SEPs.

PG&E does not currently have a recommendation on this issue.

20. How California should apply requirements for biomass fuel from timber operations to out-of-state biomass facilities or in-state facilities that obtain fuel from tribal or national forest land that also wish to receive SEPs.

PG&E does not currently have a recommendation on this issue.

21. Potential alternatives to a third-party escrow account that would provide the needed assurance to lenders in order for projects to receive financing.

PG&E agrees with developers that SEPS must be financeable for projects to move forward. One way to make SEP awards guaranteed is through a third-party escrow account. PG&E has no other suggestions at this time.